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BEFORE THE BOARD OF PATENT APPEALS AND INTERFERENCES

Application Number: 10/575,030
Filing Date: December 19, 2006
Appellant(s): JALALI ET AL.

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Dan C. Hu
For Appellant

EXAMINER'S ANSWER

This is in response to the appeal brief filed 3/25/11 appealing from the Office action mailed 7/13/10.

(1) Real Party in Interest

The examiner has no comment on the statement, or lack of statement, identifying by name the real party in interest in the brief.

(2) Related Appeals and Interferences

The examiner is not aware of any related appeals, interferences, or judicial proceedings which will directly affect or be directly affected by or have a bearing on the Board's decision in the pending appeal.

(3) Status of Claims

The following is a list of claims that are rejected and pending in the application:

Claims 1-17, 19-29, 31-33, 37, 38

(4) Status of Amendments After Final

The examiner has no comment on the appellant's statement of the status of amendments after final rejection contained in the brief.

(5) Summary of Claimed Subject Matter

The examiner has no comment on the summary of claimed subject matter contained in the brief.

(6) Grounds of Rejection to be Reviewed on Appeal

The examiner has no comment on the appellant's statement of the grounds of rejection to be reviewed on appeal. Every ground of rejection set forth in the Office action from which the appeal is taken (as modified by any advisory actions) is being maintained by the examiner except for the grounds of rejection (if any) listed under the subheading "WITHDRAWN REJECTIONS." New grounds of rejection (if any) are provided under the subheading "NEW GROUNDS OF REJECTION."

(7) Claims Appendix

The examiner has no comment on the copy of the appealed claims contained in the Appendix to the appellant's brief.

(8) Evidence Relied Upon

2004/0084180	Shah et al	5-2004
3,913,398	Curtis	10-1975
6,082,454	Tubel	7-2000

Finsterle, S., "iTough2 User's Guide", Earth Sciences Division, Lawrence Berkley National Laboratory, University of California, May 2000

Akin, Serhat, "Analysis of Tracer Tests with Simple Spreadsheet Models", Computers and Geosciences, 27, pages 171-178, 2001

(9) Grounds of Rejection

The following ground(s) of rejection are applicable to the appealed claims:

Claims 1-7, 12-15, 17, 19-22, 25-29, 31, 32, 37 and 38 are rejected under 35 U.S.C. 102(e) as being anticipated by Shah et al (US Patent Application Publication 2004/0084180).

As to **Claim 1**, Shah et al teaches: <u>a method of determining production rates in a well</u> (paragraph 0005, "…methods and systems for estimating multi-phase fluid flow rates in a subterranean well…"; paragraph 0009, "…estimates multi-fluid flow rates are provided for a plurality of selected well locations"), <u>comprising: determining a model of temperature as a function of zonal flow rates in the well</u> (paragraph 0025, lines 4-6, "It is well known that each of the entries 24 has its own fluid phase (whether it be oil, water or gas), flow rate, temperature and hydrocarbon mixture composition"; paragraph 0027, lines 1-14, "…the model 30 takes into account the conservation of energy and mass, and consequently simulates the evolution of the temperature of the flowing fluid…It is known that pressure and temperature of the flowing fluids change as they travel up or down a flow path…Therefore, model 30 should take such factors into consideration";

paragraph 0029, lines 8-11, “The user of the invention may specify…the temperature at each entry point 24 within the well 10"; paragraph 0036, lines 9-12, "In step 106, the mathematical model for the wellbore 12 is run to calculate the expected pressure and temperature values at the downhole sensor locations..."); measuring temperatures at a plurality of locations in the well (paragraph 0015; paragraph 0025, lines 16-24, “…a plurality of sensors 27 are deployed to take measurements at the various production zones 26 or other production points of interest inside the wellbore 12..."); and inverting, by a computer, the measured temperatures by applying the model to determine an allocation of production rates from different producing zones in the well (Figure 2 and description, paragraph 0030; paragraph 0039, lines 4-5; paragraph 0031, lines 1-4, “The data path 31 supplies transient data to the model, 30, such as...temperature data 43 measured at multiple downhole locations"; paragraph 0036, "Transient well data is measured...including pressure and temperature data in the wellbore 12 above each flow entry being produced...measurement above each flow entry is not required for the solution of the inverse problem…In step 106, the mathematical model of the wellbore 12 is run to calculate the expected pressure and temperature values at the downhole sensor locations, the expected volumetric phase flow rates at the wellhead 22, and sensitivity coefficients of the model response to each phase flow rate at each fluid entry location”; paragraph 0037, lines 4-10, “…the model-calculated expected pressure and temperature values for various well locations of step 106 are preferably compared with the measured temperature and pressure values obtained in step 104 with respect to those same well locations…”; paragraph 0038, “…the deviation between the calculated

and measured quantities (of step 108) may be used with the sensitivity coefficients of the model (from step 106) to determine changes necessary...In this way, the modeling comparisons may be reiterated...until an approximate match (within acceptable tolerances) is obtained between the calculated well properties and related flow rates and the measured well properties and flow rates...if the measured volumetric phase rates and pressure and temperature readings are in tolerable agreement with the expected values predicted by the model 30, the final estimates of the multiphase flow rates are provided as shown in step 118"; claim 27, "…the multiphase fluid flow rate program further comprises a model inversion algorithm"; paragraph 0009, "…estimated multi-fluid flow rates are provided for a plurality of selected well locations"); wherein the inverting comprising using an optimization algorithm that solves an optimization problem for calculating the production rates (Figure 3, elements 108, 110; paragraph 0006, lines 5-8, "The multi-phase fluid flow rates are estimated by iteratively comparing measured static and transient well conditions with the model for the well"; paragraphs 0037-0038, "…In step 108, the model-calculated expected pressure and temperature values for various well locations of step 106 are preferably compared with the measured temperature and pressure values obtained in step 104 with respect to those same well locations. Thus at step 108, the actual transient data is compared with the calculated expectations of the model…", "…the deviation between the calculated and measured quantities (of step 108) may be used with the sensitivity coefficients of the model (from step 106) to determine changes necessary...In this way, the modeling comparisons may be reiterated...until an approximate match (within acceptable tolerances) is obtained

between the calculated well properties and related flow rates and the measured well properties and flow rates...if the measured volumetric phase rates and pressure and temperature readings are in tolerable agreement with the expected values predicted by the model 30, the final estimates of the multiphase flow rates are provided as shown in step 118"), where the optimization problem minimizes an error between the measured temperatures and corresponding temperatures calculated by the model (Figure 3, elements 108, 112; paragraphs 0037 and 0038, "...the deviation between the calculated and measured quantities (of step 108) may be used with the sensitivity coefficients of the model (from step 106) to determine changes necessary for the estimate of phase flow rates at each well entry point...the modeling comparisons may be reiterated...until an approximate match (within acceptable tolerances) is obtained between the calculated well properties and related flow rates and the measured well properties and flow rates...").

As to **Claim 2**. Shah et al teaches: wherein determining the model comprises determining the model for a single-phase liquid producing well (paragraph 0026, lines 1-7).

As to **Claim 3**, Shah et al teaches: wherein determining the model comprises determining the model for a multi-layer producing well (Figure 1; paragraph 0025, lines 10-13).

As to **Claim 4**, Shah et al teaches: wherein determining the model comprises determining the model for a multi-layer, single-phase liquid producing well (Figure 1; paragraph 0025, lines 10-13; paragraph 0026, lines 1-7).

As to **Claim 5**, Shah et al teaches: wherein determining the model comprises determining the model for a multi-layer, multi-phase liquid producing well (Figure 1; paragraph 0025, lines 10-13; paragraph 0026, lines 1-7).

As to **Claim 6**, Shah et al teaches: wherein measuring the temperatures comprises measuring temperature with a distributed temperature sensor (paragraph 0025, lines 16-24).

As to **Claim 7**, Shah et al teaches: wherein the inverting comprises determining a degree of certainty in the production rates allocated (paragraph 0012; paragraph 0037, lines 9-12; paragraph 0038, lines 6-15).

As to **Claim 37**, Shah et al teaches: measuring a total flow rate of the well at a wellhead (paragraph 0011, lines 7-9, "…measuring…the wellhead flow rate…"; paragraph 0036, lines 8-9, "Volumetric flow rate measurements for each phase at the wellhead 22 are also obtained"; Figure 3, step 104; Figure 4, element 70; paragraph 0041, lines 1-2, "…the wellhead flow rate is also provided to the model…"); and allocating, by the model, the total flow rate among the different producing zones based on the measured temperatures (paragraph 0031, lines 1-4, "The data path 31 supplies transient data to the model, 30, such as...temperature data 43 measured at multiple downhole locations"; paragraph 0036, "Transient well data is measured...including pressure and temperature data in the wellbore 12 above each flow entry being produced...measurement above each flow entry is not required for the solution of the inverse problem…In step 106, the mathematical model of the wellbore 12 is run to calculate the expected pressure and temperature values at the downhole sensor

locations, the expected volumetric phase flow rates at the wellhead 22, and sensitivity coefficients of the model response to each phase flow rate at each fluid entry location"; paragraph 0037, lines 4-10, "…the model-calculated expected pressure and temperature values for various well locations of step 106 are preferably compared with the measured temperature and pressure values obtained in step 104 with respect to those same well locations…"; paragraph 0038, "…the deviation between the calculated and measured quantities (of step 108) may be used with the sensitivity coefficients of the model (from step 106) to determine changes necessary...In this way, the modeling comparisons may be reiterated...until an approximate match (within acceptable tolerances) is obtained between the calculated well properties and related flow rates and the measured well properties and flow rates...if the measured volumetric phase rates and pressure and temperature readings are in tolerable agreement with the expected values predicted by the model 30, the final estimates of the multiphase flow rates are provided as shown in step 118"; claim 27, "…the multiphase fluid flow rate program further comprises a model inversion algorithm"; paragraph 0009, "…estimated multi-fluid flow rates are provided for a plurality of selected well locations").

As to **Claim 12**, Shah et al teaches: <u>a method of determining flow rates in a well</u> (paragraph 0005, "…methods and systems for estimating multi-phase fluid flow rates in a subterranean well…"; paragraph 0009, "…estimates multi-fluid flow rates are provided for a plurality of selected well locations"), <u>comprising: measuring temperatures at a plurality of points along the well</u> (paragraph 0015; paragraph 0025, lines 16-24, "…a

plurality of sensors 27 are deployed to take measurements at the various production zones 26 or other production points of interest inside the wellbore 12...") having a plurality of well zones and a plurality of liquid phases (Figure 1; paragraph 0025, lines 10-13; paragraph 0026, lines 1-7); measuring a total flow rate from the well (paragraph 0011, lines 7-9, "…measuring…the wellhead flow rate…"; paragraph 0036, lines 8-9, "Volumetric flow rate measurements for each phase at the wellhead 22 are also obtained"; Figure 3, step 104; Figure 4, element 70; paragraph 0041, lines 1-2, "…the wellhead flow rate is also provided to the model…"); and determining, by a computer, flow rates of the plurality of liquid phases through each of the plurality of well zones (Abstract, lines 7-10, "Multi-phase fluid flow estimates may be obtained for the various liquid and gaseous fluids in the well (10) at multiple well locations (24)"; paragraph 0009, "...estimated multi-fluid flow rates are provided for a plurality of selected well locations"; Figure 2 and description, paragraph 0030; paragraph 0039, lines 4-5; paragraph 0036, lines 9-14, "…sensitivity coefficients of the model response to each phase flow rate at each fluid entry location…"; paragraph 0037, lines 1-4, "...the expected wellhead volumetric flow of each phase calculated in step 106 is compared with the measured volumetric phase flow rate obtained instep 104"; paragraph 0038, "…the modeling comparisons may be re-iterated...until an approximate match (within acceptable tolerances) is obtained between the calculated well properties and related flow rates and the measured well properties and flow rates...the final estimates of multiphase flow rates are provided...") via the measured temperatures (paragraph 0011, "…the method of estimating multi-phase fluid flow rates in a subterranean well...Steps

are also provided for measuring the transient temperature, pressure and wellhead flow rate. The subterranean well is modeled using these measurements to estimate the multi-phase low rates in the subterranean well"; paragraph 0031, lines 1-4, “The data path 31 supplies transient data to the model, 30, such as...temperature data 43 measured at multiple downhole locations"; Figure 3, element 104-118 and description, paragraphs 0036-0038); <u>wherein the determining comprises inverting the measured temperatures by applying a model</u> (paragraph 0031, lines 1-4, “The data path 31 supplies transient data to the model, 30, such as...temperature data 43 measured at multiple downhole locations"; paragraph 0036, "Transient well data is measured...including pressure and temperature data in the wellbore 12 above each flow entry being produced...measurement above each flow entry is not required for the solution of the inverse problem…In step 106, the mathematical model of the wellbore 12 is run to calculate the expected pressure and temperature values at the downhole sensor locations, the expected volumetric phase flow rates at the wellhead 22, and sensitivity coefficients of the model response to each phase flow rate at each fluid entry location”; paragraph 0037, lines 4-10, “…the model-calculated expected pressure and temperature values for various well locations of step 106 are preferably compared with the measured temperature and pressure values obtained in step 104 with respect to those same well locations…”; paragraph 0038, “…the deviation between the calculated and measured quantities (of step 108) may be used with the sensitivity coefficients of the model (from step 106) to determine changes necessary...In this way, the modeling comparisons may be reiterated...until an approximate match (within acceptable

tolerances) is obtained between the calculated well properties and related flow rates and the measured well properties and flow rates...if the measured volumetric phase rates and pressure and temperature readings are in tolerable agreement with the expected values predicted by the model 30, the final estimates of the multiphase flow rates are provided as shown in step 118"; claim 27, "…the multiphase fluid flow rate program further comprises a model inversion algorithm"; paragraph 0009, "…estimated multi-fluid flow rates are provided for a plurality of selected well locations"), <u>wherein the inverting comprises allocating by the total flow rate among the plurality of well zones</u> (paragraph 0009, "…estimated multi-fluid flow rates are provided for a plurality of selected well locations"; Figure 3, element 104, "Volumetric flow rate of each phase at the well head"; Figure 4, element 70; paragraph 0011, lines 7-11; paragraph 0036, lines 8-9, "Volumetric flow rate measurements for each phase at the wellhead 22 are obtained"; paragraph 0037, lines 1-4, "…the expected wellhead volumetric flow of each phase calculated in step 106 is compared with the measured volumetric phase flow rate obtained in step 104"; paragraph 0038, "...the deviation between the calculated and measured quantities (of step 108) may be used with the sensitivity coefficients of the model (from step 106) to determine changes necessary for the estimate of phase flow rates at each well entry point...if the measured volumetric phase rates and pressure and temperature readings are in tolerable agreement with the expected values predicted by the model 30, the final estimates of the multiphase flow rates are provided as shown at step 118").

As to **Claim 13**, Shah et al teaches: wherein measuring the temperature at the plurality of points comprises utilizing a distributed temperature sensor (paragraph 0025, lines 16-24).

As to **Claim 14**, Shah et al teaches: wherein determining the flow rates comprises constructing the model of temperature as a function of zonal flow rates in the well (paragraph 0025, lines 4-6, “It is well known that each of the entries 24 has its own fluid phase (whether it be oil, water or gas), flow rate, temperature and hydrocarbon mixture composition”; paragraph 0027, lines 1-14, “…the model 30 takes into account the conservation of energy and mass, and consequently simulates the evolution of the temperature of the flowing fluid…It is known that pressure and temperature of the flowing fluids change as they travel up or down a flow path…Therefore, model 30 should take such factors into consideration”; paragraph 0029, lines 8-11, “The user of the invention may specify…the temperature at each entry point 24 within the well 10"; paragraph 0036, lines 9-12, "In step 106, the mathematical model for the wellbore 12 is run to calculate the expected pressure and temperature values at the downhole sensor locations..."), and using the model to invert the measured temperatures in allocating the flow rates from the plurality of well zones based on the measured total flow rate (paragraph 0011, lines 7-9, “wellhead flow rate”; paragraph 0031, lines 1-4, “The data path 31 supplies transient data to the model, 30, such as...temperature data 43 measured at multiple downhole locations"; paragraph 0036, "Transient well data is measured...including pressure and temperature data in the wellbore 12 above each flow entry being produced...measurement above each flow entry is not required for the

solution of the inverse problem…Volumetric flow rate measurements for each phase at the wellhead 22 are also obtained. In step 106, the mathematical model of the wellbore 12 is run to calculate the expected pressure and temperature values at the downhole sensor locations, the expected volumetric phase flow rates at the wellhead…”; paragraph 0037, lines 1-10, “…the expected volumetric flow of each phase calculated in step 106 is compared with the measured volumetric phase flow rate obtained in step 104…the model-calculated expected pressure and temperature values for various well locations of step 106 are preferably compared with the measured temperature and pressure values obtained in step 104 with respect to those same well locations…”; paragraph 0038, “…the deviation between the calculated and measured quantities (of step 108) may be used with the sensitivity coefficients of the model (from step 106) to determine changes necessary...In this way, the modeling comparisons may be reiterated...until an approximate match (within acceptable tolerances) is obtained between the calculated well properties and related flow rates and the measured well properties and flow rates...if the measured volumetric phase rates and pressure and temperature readings are in tolerable agreement with the expected values predicted by the model 30, the final estimates of the multiphase flow rates are provided as shown in step 118"; claim 27, “…the multiphase fluid flow rate program further comprises a model inversion algorithm”; paragraph 0009, “…estimated multi-fluid flow rates are provided for a plurality of selected well locations”).

As to **Claim 15**, Shah et al teaches: wherein determining the flow rates comprises determining flow rates of oil and water phases during production (Abstract,

lines 7-10, “Multi-phase fluid flow estimates may be obtained for the various liquid and gaseous fluids in the well (10) at multiple well locations (24)”; paragraph 0009, “...estimated multi-fluid flow rates are provided for a plurality of selected well locations"; paragraph 0037, lines 1-4, "...the expected wellhead volumetric flow of each phase calculated in step 106 is compared with the measured volumetric phase flow rate obtained instep 104”; paragraph 0038, lines 11-15, “…if the measured volumetric phase rates…are intolerable agreement with the expected values predicted by the model 30, the final estimates of the multiphase flow rates are provided..."; paragraph 0035, line 5; paragraph 0028, lines 1-4).

As to **Claim 17**, Shah et al teaches: wherein inverting the measured temperatures comprises utilizing an optimization algorithm that solves an optimization problem for calculating the flow rates, where the optimization problem minimizes an error between the measured temperatures and corresponding temperatures calculated by the model (Figure 3 and description, paragraphs 0033-0038).

As to **Claim 19**, Shah et al teaches: <u>a system</u> (Figures 1, 2), <u>comprising: a temperature sensor deployable with a production completion along a wellbore to sense temperature data at a plurality of wellbore locations during production</u> (paragraph 0025, lines 16-24, “…a plurality of sensors 27 are deployed to take measurements at the various production zones 26 or other points of interest inside the wellbore 12. The sensors 27 are preferably downhole temperature and pressure transducers coupled to computer 32...may include fiber optic distributed temperature sensing ("DTS")

systems..."); <u>and a processor system configured to receive the sensed temperature data and allocate flow rates from a plurality of wellbore zones based on the sensed temperature data</u> (paragraph 0025, lines 16-24, “The sensors 27 are preferably downhole temperature and pressure transducers coupled to computer 32…”; paragraph 0026, lines 5, “…the computer 32 incorporates the functionality of a mathematical model 30 designed to simulate the physical processes of the flow of multi-phase fluid...within the wellbore 12"; paragraph 0031, lines 1-4; paragraphs 0036-0038; paragraph 0009, “…estimated multi-fluid flow rates are provided for a plurality of selected well locations”), <u>wherein the processor system is configured to allocate the flow rates by inverting the sensed temperature data using a temperature forward model</u> (paragraph 0039, lines 4-5; paragraph 0031, lines 1-4, “The data path 31 supplies transient data to the model, 30, such as...temperature data 43 measured at multiple downhole locations"; paragraph 0036, "Transient well data is measured...including pressure and temperature data in the wellbore 12 above each flow entry being produced...measurement above each flow entry is not required for the solution of the inverse problem…In step 106, the mathematical model of the wellbore 12 is run to calculate the expected pressure and temperature values at the downhole sensor locations, the expected volumetric phase flow rates at the wellhead 22, and sensitivity coefficients of the model response to each phase flow rate at each fluid entry location”; paragraph 0037, lines 4-10, “…the model-calculated expected pressure and temperature values for various well locations of step 106 are preferably compared with the measured temperature and pressure values obtained in step 104 with respect to those same well locations…”; paragraph 0038,

"…the deviation between the calculated and measured quantities (of step 108) may be used with the sensitivity coefficients of the model (from step 106) to determine changes necessary...In this way, the modeling comparisons may be reiterated...until an approximate match (within acceptable tolerances) is obtained between the calculated well properties and related flow rates and the measured well properties and flow rates...if the measured volumetric phase rates and pressure and temperature readings are in tolerable agreement with the expected values predicted by the model 30, the final estimates of the multiphase flow rates are provided as shown in step 118"; claim 27, "…the multiphase fluid flow rate program further comprises a model inversion algorithm"; paragraph 0009, "…estimated multi-fluid flow rates are provided for a plurality of selected well locations"), <u>wherein the inverting comprises using an optimization algorithm that solves an optimization problem for calculating the flow rates</u> (Figure 3, elements 108, 110; paragraph 0006, lines 5-8, "The multi-phase fluid flow rates are estimated by iteratively comparing measured static and transient well conditions with the model for the well"; paragraphs 0037-0038, "…In step 108, the model-calculated expected pressure and temperature values for various well locations of step 106 are preferably compared with the measured temperature and pressure values obtained in step 104 with respect to those same well locations. Thus at step 108, the actual transient data is compared with the calculated expectations of the model…", "…the deviation between the calculated and measured quantities (of step 108) may be used with the sensitivity coefficients of the model (from step 106) to determine changes necessary...In this way, the modeling comparisons may be reiterated...until an

approximate match (within acceptable tolerances) is obtained between the calculated well properties and related flow rates and the measured well properties and flow rates...if the measured volumetric phase rates and pressure and temperature readings are in tolerable agreement with the expected values predicted by the model 30, the final estimates of the multiphase flow rates are provided as shown in step 118"), <u>where the optimization problem minimizes an error between the sensed temperature data and corresponding calculated temperature data from the model</u> (Figure 3, elements 108, 112; paragraphs 0037 and 0038, "...the deviation between the calculated and measured quantities (of step 108) may be used with the sensitivity coefficients of the model (from step 106) to determine changes necessary for the estimate of phase flow rates at each well entry point...the modeling comparisons may be reiterated...until an approximate match (within acceptable tolerances) is obtained between the calculated well properties and related flow rates and the measured well properties and flow rates...").

As to **Claim 20**, Shah et al teaches: wherein the temperature forward model specifies temperature as a function of zonal flow rates (*model in which temperature is a function of zonal flow rates*: paragraph 0025, lines 4-6, “It is well known that each of the entries 24 has its own fluid phase (whether it be oil, water or gas), flow rate, temperature and hydrocarbon mixture composition”; paragraph 0027, lines 1-14, “…the model 30 takes into account the conservation of energy and mass, and consequently simulates the evolution of the temperature of the flowing fluid…It is known that pressure and temperature of the flowing fluids change as they travel up or down a flow path…Therefore, model 30 should take such factors into consideration”; paragraph

0029, lines 8-11, “The user of the invention may specify…the temperature at each entry point 24 within the well 10"; paragraph 0036, lines 9-12, "In step 106, the mathematical model for the wellbore 12 is run to calculate the expected pressure and temperature values at the downhole sensor locations...").

As to **Claim 21**, Shah et al teaches: wherein the temperature sensor comprises a distributed temperature sensor (paragraph 0025, lines 16-24, “…a plurality of sensors 27 are deployed to take measurements at the various production zones 26 or other points of interest inside the wellbore 12. The sensors 27 are preferably downhole temperature and pressure transducers coupled to computer 32...may include fiber optic distributed temperature sensing ("DTS") systems...").

As to **Claim 22**, Shah et al teaches: wherein the processor system is configured to allocate flow rates in a multi-layer, multi-phase liquid producing well (Figure 1; paragraph 0025, lines 10-13; paragraph 0026, lines 1-7).

As to **Claim 25**, Shah et al teaches: wherein the wellbore is oriented generally vertically (Figure 1; paragraph 0024, lines 11-15).

As to **Claim 38**, Shah et al teaches: a sensor to measure a total flow rate of the wellbore at a wellhead (paragraph 0011, lines 7-9, “…measuring the transient temperature, pressure and wellhead flow rate”; paragraph 0036, lines 8-9, “Volumetric flow rate measurements for each phase at the wellhead 22 are obtained…”; paragraph 0002, lines 5-16, wherein it is known in the art to use these techniques to measure wellhead flow rate); wherein the processor system is configured to allocate, using the model, the total flow rate among the plurality of wellbore zones based on the sensed

temperature data to allocate flow rates (paragraph 0031, lines 1-4, “The data path 31 supplies transient data to the model, 30, such as...temperature data 43 measured at multiple downhole locations"; paragraph 0036, "Transient well data is measured...including pressure and temperature data in the wellbore 12 above each flow entry being produced...measurement above each flow entry is not required for the solution of the inverse problem…In step 106, the mathematical model of the wellbore 12 is run to calculate the expected pressure and temperature values at the downhole sensor locations, the expected volumetric phase flow rates at the wellhead 22, and sensitivity coefficients of the model response to each phase flow rate at each fluid entry location”; paragraph 0037, lines 4-10, “…the model-calculated expected pressure and temperature values for various well locations of step 106 are preferably compared with the measured temperature and pressure values obtained in step 104 with respect to those same well locations…”; paragraph 0038, “…the deviation between the calculated and measured quantities (of step 108) may be used with the sensitivity coefficients of the model (from step 106) to determine changes necessary...In this way, the modeling comparisons may be reiterated...until an approximate match (within acceptable tolerances) is obtained between the calculated well properties and related flow rates and the measured well properties and flow rates...if the measured volumetric phase rates and pressure and temperature readings are in tolerable agreement with the expected values predicted by the model 30, the final estimates of the multiphase flow rates are provided as shown in step 118"; claim 27, “…the multiphase fluid flow rate

program further comprises a model inversion algorithm”; paragraph 0009, “…estimated multi-fluid flow rates are provided for a plurality of selected well locations”).

As to **Claim 26**, Shah et al teaches: <u>a method, comprising: deploying a distributed temperature sensor along a wellbore</u> (paragraph 0025, lines 16-24, “…a plurality of sensors 27 are deployed to take measurements at the various production zones 26 or other points of interest inside the wellbore 12. The sensors 27 are preferably downhole temperature and pressure transducers coupled to computer 32...may include fiber optic distributed temperature sensing ("DTS") systems..."); <u>utilizing a model of temperature as a function of fluid flow rates in the wellbore</u> (paragraph 0025, lines 4-6, “It is well known that each of the entries 24 has its own fluid phase (whether it be oil, water or gas), flow rate, temperature and hydrocarbon mixture composition”; paragraph 0027, lines 1-14, “…the model 30 takes into account the conservation of energy and mass, and consequently simulates the evolution of the temperature of the flowing fluid…It is known that pressure and temperature of the flowing fluids change as they travel up or down a flow path…Therefore, model 30 should take such factors into consideration”; paragraph 0029, lines 8-11, “The user of the invention may specify…the temperature at each entry point 24 within the well 10"; paragraph 0036, lines 9-12, "In step 106, the mathematical model for the wellbore 12 is run to calculate the expected pressure and temperature values at the downhole sensor locations..."); <u>obtaining measured temperatures from the distributed temperature sensor</u> (paragraph 0025, lines 16-24, “…a plurality of sensors 27 are deployed to take

measurements at the various production zones 26 or other points of interest inside the wellbore 12. The sensors 27 are preferably downhole temperature and pressure transducers coupled to computer 32…"; paragraph 0031, lines 1-4, "The data path 31 supplies transient data to the model 30, such as…temperature data 43…"Figure 3, element 104); <u>determining fluid flow rates in corresponding wellbore zones using the measured temperatures in conjunction with the model</u> (paragraphs 0036-0038; paragraph 0009, "…estimated multi-fluid flow rates are provided for a plurality of selected well locations"); <u>wherein the determined fluid flow rates are calculated using an optimization algorithm that solves an optimization problem</u> (Figure 3, elements 108, 110; paragraph 0006, lines 5-8, "The multi-phase fluid flow rates are estimated by iteratively comparing measured static and transient well conditions with the model for the well"; paragraphs 0037-0038, "…In step 108, the model-calculated expected pressure and temperature values for various well locations of step 106 are preferably compared with the measured temperature and pressure values obtained in step 104 with respect to those same well locations. Thus at step 108, the actual transient data is compared with the calculated expectations of the model…", "…the deviation between the calculated and measured quantities (of step 108) may be used with the sensitivity coefficients of the model (from step 106) to determine changes necessary...In this way, the modeling comparisons may be reiterated...until an approximate match (within acceptable tolerances) is obtained between the calculated well properties and related flow rates and the measured well properties and flow rates...if the measured volumetric phase rates and pressure and temperature readings are in tolerable agreement with the

expected values predicted by the model 30, the final estimates of the multiphase flow rates are provided as shown in step 118"), where the optimization problem minimizes an error between the measured temperatures and corresponding temperatures calculated by the model (Figure 3, elements 108, 112; paragraphs 0037 and 0038, "...the deviation between the calculated and measured quantities (of step 108) may be used with the sensitivity coefficients of the model (from step 106) to determine changes necessary for the estimate of phase flow rates at each well entry point...the modeling comparisons may be reiterated...until an approximate match (within acceptable tolerances) is obtained between the calculated well properties and related flow rates and the measured well properties and flow rates...").

As to **Claim 27**, Shah et al teaches: wherein determining the fluid flow rates comprises inverting the measured temperatures using the model to obtain the fluid flow rates (paragraph 0031, lines 1-4, “The data path 31 supplies transient data to the model, 30, such as...temperature data 43 measured at multiple downhole locations"; paragraph 0036, "Transient well data is measured...including pressure and temperature data in the wellbore 12 above each flow entry being produced...measurement above each flow entry is not required for the solution of the inverse problem…In step 106, the mathematical model of the wellbore 12 is run to calculate the expected pressure and temperature values at the downhole sensor locations…”; paragraph 0037, lines 4-10, “…the model-calculated expected pressure and temperature values for various well locations of step 106 are preferably compared with the measured temperature and pressure values obtained in step 104 with respect to those same well locations…”;

paragraph 0038, "…the deviation between the calculated and measured quantities (of step 108) may be used with the sensitivity coefficients of the model (from step 106) to determine changes necessary...In this way, the modeling comparisons may be reiterated...until an approximate match (within acceptable tolerances) is obtained between the calculated well properties and related flow rates and the measured well properties and flow rates...if the measured volumetric phase rates and pressure and temperature readings are in tolerable agreement with the expected values predicted by the model 30, the final estimates of the multiphase flow rates are provided as shown in step 118"; claim 27, "…the multiphase fluid flow rate program further comprises a model inversion algorithm").

As to **Claim 28**, Shah et al teaches: wherein deploying the distributed temperature sensor comprises deploying the distributed temperature sensor in a generally vertical wellbore (Figure 1, element 27; paragraph 0024, lines 11-15).

As to **Claim 29**, Shah et al teaches: wherein deploying the distributed temperature sensor comprises deploying the distributed temperature sensor in a deviated wellbore (Figure 1, element 27; paragraph 0024, lines 11-15).

As to **Claim 31**, Shah et al teaches: wherein determining the fluid flow rates comprises determining flow rates for a single-phase liquid producing well (paragraph 0026, lines 1-7; paragraph 0025, line 5).

As to **Claim 32**, Shah et al teaches: wherein determining the fluid flow rates comprises determining flow rates for a multi-phase liquid producing well (paragraph 0026, lines 1-7; paragraph 0025, line 5).

Claims 8-10 and 33 are rejected under 35 U.S.C. 103(a) as being unpatentable over Shah et al as applied to claims 1, 7 and 26 above, in view of Finsterle ("iTough2 User's Guide", Earth Sciences Division, Lawrence Berkley National Laboratory, University of California, May 2000).

Shah et al teaches a method of determining production rates in a well comprising inverting measured temperatures by applying a model of temperature as a function of zonal flow rates in a well to determine an allocation of production rates from different producing zones in the well, wherein inverting comprises determining a degree of certainty in the production rates allocated, allocating flow rate in at least one wellbore zone using temperature data in conjunction of the model, and determining error in the fluid flow rate and compensating for model error when inverting using the model to determine the fluid flow rates (Figure 3, elements 108, 112; paragraph 0038).

Shah et al does not expressly teach: (claim 8) wherein determining the degree of certainty comprises determining a degree of error in the model, the method further comprising compensating for the determined degree of error in the model in performing the inverting; (claim 9) wherein determining a degree of certainty comprises determining a degree of error in the measured temperatures, the method further comprising compensating for the determined degree of error in the model in performing the inverting; (claim 10) wherein determining the degree of certainty comprises determining a degree of error in well parameter values, the method further comprising compensating for the determined degree of error in the model in performing the inverting; (claim 33)

determining a model error, a measurement error, and a well parameter error; and compensating for model error, measurement error and well parameter error when inverting using the model to determine the fluid flow rates.

Finsterle teaches that in predicting multiphase fluid and heat flow in the subsurface by means of numerical simulation, errors in the conceptual model usually have the largest impact on model predictions, and assigning parameter values to the numerical model is likely to be tedious and challenging (page 2, paragraphs 1 and 2) and therefore teaches the iTOUGH2 computer program that provides inverse modeling capabilities for the TOUGH2 simulator (a numerical simulator for multidimensional, nonisothermal flows of multiphase, multicomponent fluids in porous and fractured media) that not only estimates model-related parameters by automatically calibrating TOUGH2 models to laboratory or field data, the information obtained by evaluating the sensitivity of the calculated system response with respect to certain input parameters can be used to study the appropriateness of a proposed experimental design and to analyze the uncertainty of model predictions (page 4, paragraph 1). The iTOUGH2 program taught by Finsterle includes (**claim 8, 33**) determining a degree of error in the model (page 4, section (2), “error analysis is performed”; page 7, item (4), “…Model output and measured data are compared only at discrete points in space and time, the so-called calibration points”, equation 1.5.3 and description); (**claim 9, 33**) determining a degree of error in the measurements (page 3, paragraph 2, lines 4-5; page 10, item 5; page 27, element 2.5.3.1); (**claim 10, 33**) determining a degree of error in model parameter values (page 4, section (2), “error analysis is performed”; page 8, items 7

and 8, "objective function"); (**claims 8, 9, 10, 33**) and compensating for model error, measurement error and model parameter error when inverting (page 6, items 8-9; page 8, items (8 and 9), "...find the minimum objecting function by iteratively updating the model parameters. Since the model output z(p) depends on the parameters to be estimated, the fit can be improved by changing the elements of parameter vector p…"; page 10, item 5 and page 11, equation 1.6.2 that shows the objective function to be minimized, S, includes measurement errors).

Shah et al and Finsterle are analogous art since they are both directed to modeling multiphase flows in a subsurface by means of inverse modeling.

It would have been obvious to one of ordinary skill in the art at the time the invention was made to modify the method of determining production rates in a well comprising inverting measured temperatures by applying a model of temperature as a function of zonal flow rates in a well to determine an allocation of production rates from different producing zones in the well, wherein inverting comprises determining a degree of certainty in the production rates allocated, allocating flow rate in at least one wellbore zone using temperature data in conjunction of the model, determining error in the fluid flow rate and compensating for model error when inverting using the model to determine the fluid flow rates as taught by Shah et al to further include (claims 8, 33) wherein determining the degree of certainty comprises determining a degree of error in the model; (claims 9, 33) wherein determining a degree of certainty comprises determining a degree of error in the measurements (measured temperatures); (claims 10, 33) wherein determining the degree of certainty comprises determining a degree of error in

model (well) parameter values; (claims 8, 9, 10, 33) wherein determining error in the fluid flow rate comprises compensating for model error, measurement error and well parameter error as taught by Finsterle since Finsterle teaches that in predicting multiphase fluid and heat flow in the subsurface by means of numerical simulation, errors in the conceptual model usually have the largest impact on model predictions, and assigning parameter values to the numerical model is likely to be tedious and challenging (page 2, paragraphs 1 and 2) and therefore teaches the iTOUGH2 computer program that provides inverse modeling capabilities for the TOUGH2 simulator (a numerical simulator for multidimensional, nonisothermal flows of multiphase, multicomponent fluids in porous and fractured media) that not only estimates model-related parameters by automatically calibrating TOUGH2 models to laboratory or field data, the information obtained by evaluating the sensitivity of the calculated system response with respect to certain input parameters can be used to study the appropriateness of a proposed experimental design and to analyze the uncertainty of model predictions (page 4, paragraph 1).

Claim 11 is rejected under 35 U.S.C. 103(a) as being unpatentable over Shah et al as applied to claim 1 above, in view of Akin ("Analysis of Tracer Tests with Simple Spreadsheet Models", Computers and Geosciences, 27, pages 171-178, 2001).

Shah et al teaches a method of determining production rates in a well comprising inverting measured temperatures by applying a model of temperature as a function of zonal flow rates in a well to determine an allocation of production rates from different

producing zones in the well, wherein the inverting comprises an optimization algorithm (Figure 3 and description, paragraphs 0033, 0036-0038).

Shah does not expressly teach wherein using the optimization algorithm comprises utilizing a generalized reduced gradient optimization algorithm.

Akin teaches a method of matching field data to predictions from computer simulation programs in tracer studies used for reservoir characterization that uses function evaluations rather than full simulator runs that results in a large reduction in computing time (Abstract, lines 4-7; section 1, paragraph 1, sentence 1; section 1, paragraph 2, lines 1-6 and lines 20-28), wherein after the reservoir models are implemented in a spreadsheet, the models were then matched to experimental data using the Generalized Reduced Gradient nonlinear optimization code to minimize the objective function (page 174, column 2, paragraph 4).

Shah et al and Akin are analogous art since they are both directed to modeling a reservoir using inverse modeling techniques that match the models to experimental data using optimization techniques that minimize an objective function.

It would have been obvious to one of ordinary skill in the art at the time the invention was made to modify the optimization algorithm as taught by Shah to utilize a generalized reduced gradient optimization algorithm as taught by Akin since Akin teaches a method of matching field data to predictions from computer simulation programs in tracer studies used for reservoir characterization that uses function evaluations rather than full simulator runs that results in a large reduction in computing

time (Abstract, lines 4-7; section 1, paragraph 1, sentence 1; section 1, paragraph 2, lines 1-6 and lines 20-28).

Claim 16 is rejected under 35 U.S.C. 103(a) as being unpatentable over Shah as applied to claim 12 above, and further in view of Curtis (US Patent 3,913,398).

Shah et al teaches a method of determining flow rates in a well comprising determining flow rates of a plurality of liquid phases through each of a plurality of well zones via measured temperatures.

Shah et al does not expressly teach wherein determining the flow rates comprises determining flow rates of fluid injected into each of the plurality of well zones.

Curtis teaches that temperature data has been useful in the studies of secondary recovery of crude petroleum and that in the secondary recovery of crude petroleum, it is important not only to locate each permeable formation accepting fluid but also to determine the flow rates at which the fluid enters each formation (column 1, lines 24-33) and teaches that determining flow rates of fluid injected into a plurality of well zones using temperature data is well known in the art (column 1, lines 34-50; column 2, lines 27-41).

Shah et al and Curtis are analogous art since they are both directed to determining flow rates of fluids (such as oil) produced in wells at each of a plurality of possible entry points through the use of temperature data.

It would have been obvious to one of ordinary skill in the art at the time the invention was made to modify the method of determining flow rates in a well comprising

determining flow rates of a plurality of liquid phases through each of a plurality of well zones via measured temperatures as taught by Shah to further include determining flow rates of fluid injected into each of the plurality of well zones as taught by Curtis since Curtis teaches that temperature data has been useful in the studies of secondary recovery of crude petroleum and that in the secondary recovery of crude petroleum, it is important not only to locate each permeable formation accepting fluid but also to determine the flow rates at which the fluid enters each formation (column 1, lines 26-33) and teaches that determining flow rates of fluid injected into a plurality of well zones using temperature data is well known in the art (column 1, lines 34-50; column 2, lines 27-41).

Claims 23 and 24 are rejected under 35 U.S.C. 103(a) as being unpatentable over Shah as applied to claim 19 above, in view of Tubel (US Patent 6,082,454).

Shah et al teaches a system comprising a production completion in a wellbore (Figure 1, elements 14, 16, 18, 20, 22, 24, 28).

Shah does not expressly teach that the production completion (claim 23) comprises an electric submersible pumping system or (claim 24) a gas lift system.

Tubel teaches spooled coiled tubing strings (production/completion strings) which include desired devices and sensors that are assembled and tested at the factory prior to the deployment of the string such that it substantially increases the quality and reliability of such strings and reduces the deployment or retrieval time (column 2, lines 7-21), wherein a production completion according to the invention comprises devices

typically used with a production completion such as an electrical submersible pump and/or a gas lift device according to the particular application (column 5, lines 29-36).

Shah and Tubel are analogous art since they are both directed to production completions deployed in a wellbore.

It would have been obvious to one of ordinary skill in the art at the time the invention was made to modify the production completion as taught by Shah to further include an electric submersible pumping system and a gas lift system as taught by Tubel since Tubel teaches spooled coiled tubing strings (production/completion strings) which include desired devices and sensors that are assembled and tested at the factory prior to the deployment of the string such that it substantially increases the quality and reliability of such strings and reduces the deployment or retrieval time (column 2, lines 7-21), wherein the devices include an electrical submersible pump and/or a gas lift device among others that are used with the production string according to the particular application (column 5, lines 29-36).

(10) Response to Argument

<u>Claims 1-7, 12-15, 17, 19-22, 25-29, 31, 32, 37, 38</u>

Claims 1-7

Appellant argues that Shah, paragraph 0006, lines 5-8 recites no hint of an optimization problem that minimizes an error between measured temperatures and corresponding temperatures calculated by a model (page 6, paragraph 2).

The Examiner cited this portion of Shah to point out that Shah's process of determining multi-phase fluid flow rates is an “iterative process” that includes comparing the “measured” conditions with “calculated” conditions from the model. It is well known in the art that an optimization process is an iterative process. Although this passage does not specifically discuss minimizing the error between the measured and calculated temperatures, the Examiner cited this passage as background information.

In regards to the Examiner's citations of paragraphs 0037, 0038 and Figure 3, elements 108, 110 and 112, Appellant argues, "...reiterating to accomplish an approximate match to within acceptable tolerances is not the same as solving an optimization problem that minimizes an error between the measured temperatures and model-calculated temperatures" (page 3, paragraph 3).

As stated in the 7/13/10 Office action (paragraph 55), it is the Examiner's position that these passages of Shah clearly teach an optimization algorithm that minimizes an error between the measured and calculated temperatures. Specifically, element 108 compares the calculated and measured temperatures. This comparison produces a "deviation", that is, the "error" or "difference", between the calculated and measured temperatures. If the "deviation" or "error" is too large (it does not fall within an acceptable tolerance level), changes are made to the model and the process is reiterated until the calculated and measured temperature deviation is within an acceptable tolerance level. These changes to the model and the reiteration of the process shown in Figure 3 and described in paragraphs 0037 and 0038 is clearly an

optimization algorithm that is minimizing the error between the model calculation and actual measured data.

In response to the Examiner’s position stated above, Appellant argues that the Examiner appears to have equated “acceptable” or “good enough” with “minimizing” which is clearly incorrect, and again argues that Shah’s teachings are quite different from solving an optimization problem that minimizes an error between the measured temperatures and model-calculated temperatures as claimed (page 6, paragraph 4-page 7, paragraph1).

It is the Examiner’s position that Shah's disclosure of making changes to the model such that the model more closely estimates the actual measured quantities is equivalent to the “minimizing” referred to by the Appellant. The Examiner is not equating "acceptable" or "good enough" with "minimizing".

Further, it is the Examiner’s position that the cited passages of Shah wherein a model is changed in a re-iterative process such that the model calculated values are within acceptable agreement with actual measured values is clearly an optimization algorithm that is minimizing the error between the calculated and measured values.

Claims 12-15

Appellant argues that paragraphs 0009 and 0011 of Shah do not teach inverting measured temperatures by applying a model that comprises allocating the total flow rate among the plurality of well zones (page 7, paragraph 5).

The Examiner cited paragraph 0009 to point out that the method of Shah "estimates multi-fluid flow rates " for a "plurality of selected well locations", that is, an allocation of flow rates is produced among a plurality of well zones by the method of Shah. Further, the Examiner cited paragraph 0011 since it discloses “measuring the transient temperature, pressure and wellhead flow rate”, that is, the “total flow rate from the well”, and modeling the well "using these measurements to estimate multi-phase fluid flow rates in the subterranean well". It is the Examiner’s position that these passages provide background information into the process taught by Shah wherein the measured temperatures and total wellhead flow rate are input into the model to determine an allocation of total flow rate among the plurality of well zones. That is, the total flow rate at the well head is allocated amongst the plurality of well zones using the model and process taught by Shah.

Appellant argues that paragraphs 0031 and 0036 of Shah do not teach or suggest Shah using a total flow rate from the well to allocate the total flow rate among the plurality of well zones in performing inverting to determine flow rates of a plurality of liquid phases through the plurality of well zones (page 7, paragraph 6 - page 8, paragraph 1).

The Examiner cited these passages to point out that measured temperatures and that total flow rate at the well head are obtained and used as input to the model. Using these inputs, the model then proceeds to provide an "estimate of phase flow rates at each well entry point" (paragraph 0038). It is the Examiner's position that this estimation

of phase flow rates at each well entry well point using the measured temperatures and total flow rate at the wellhead allocates the total flow rate measured at the well head amongst a plurality of well zones as set forth in Appellant's claims. Shah further teaches that a model inversion algorithm is used (paragraph 0036, line 5; claim 27).

The Examiner further points out that Appellant has not discussed the citation of Figure 3, step 104 that clearly shows the well head flow rates used as input to the model to estimate the flow rates at a plurality of zones.

Appellant argues that paragraphs 0037-0038 relate to reiterating the processing of the model until the deviation between measured and model-calculated quantities are within acceptable tolerances and that paragraph 0041 refers to providing the wellhead flow rate to the model, however, there is no hint in these passages that applying the model comprises allocating a total flow rate among a plurality of well zones. Appellant further argues that regardless of paragraph 0041 showing the wellhead flow rate as used as input to the model, there is no hint that the model is applied to allocate a total flow rate from the well among the plurality of well zones.

It is the Examiner's position that paragraphs 0037 and 0038 of Shah that disclose "…to determine changes necessary for <u>the estimate of phase flow rates at each entry point</u>…" and "…the final estimates of the multi-phase flow rates are provided" among other cited passages of Shah (paragraph 00009), that are determined with a model utilizing total wellhead flow rate as input (paragraph 0041) clearly teaches allocating this total wellhead flow rate amongst a plurality of well zones or entry points. A shown in

Figure 3, the total well head flow rate is input (104), the model calculates an estimated total flow rate (106), if the calculated total flow rate is in tolerable agreement with the measured flow rate (108), flow rates are allocated amongst the plurality of well zones (118).

Claim 17

Appellant argues that Shah does not disclose the limitations of Claim 17 for the reasons recited above for Claim 1 (page 8, paragraphs 5-7).

As discussed above with regard to Claim 1, it is the Examiner's position that the teachings of Shah clearly disclose the limitations of Claim 17.

Claim 37

Appellant argues that Claim 37 is allowable due to its dependency on Claim 1 and further, that Shah does not provide a teaching of the limitations of the claim as discussed in connection with Claim 12 (page 9).

As discussed above with regard to Claims 1 and 12, it is the Examiner’s position that the teachings of Shah clearly disclose the limitations of Claim 37.

Claims 19-22, 25

Appellant argues that for similar reasons to Claim 1, Shah does not provide any teachings for the limitations of Claim 19 that recite, “wherein the processor system is configured to allocate the flow rates by inverting the sensed temperature data using a

temperature forward model, wherein the inverting comprises using an optimization algorithm that solves an optimization problem for calculating the flow rates, where the optimization problem minimizes an error between the sensed temperature data and corresponding calculated temperature data from the model” (page 9).

As discussed above with regard to Claim 1, it is the Examiner’s position that the teachings of Shah clearly disclose the limitations of Claim 19.

Claims 26-29, 31, 32

Appellant argues that for reasons similar to claim 1, Shah does not disclose at least the following language of Claim 26, “wherein the determined fluid flow rates are calculated using an optimization algorithm that solves an optimization problem, wherein the optimization problem minimizes an error between the measured temperatures and corresponding temperatures calculated by the model" (page 10).

As discussed above with regard to Claim 1, it is the Examiner’s position that the teachings of Shah clearly disclose the limitations of Claim 26.

Claim 38

Appellant argues that Claim 38 depends from Claim 19 and is therefore allowable for the same reasons as Claim 19. Further, for similar reasons stated above with respect to Claim 12, Shah clearly does not provide any teaching or hint of the combination of elements recited in the claim (page 10).

As discussed above with regard to Claims 1, 12 and 19, it is the Examiner's position that the teachings of Shah clearly disclose the limitations of Claim 38.

Claims 8-10 and 33

Appellant argues with respect to the prima facie case of Shah in view of Finsterle. As cited above and further discussed below, given a reasonable interpretation of the claims, the art has been applied to each and every limitation claimed, the arts of Shah and Finsterle are analogous and therefore provide some reasonable expectation of success and finally a suggestion or motivation to combine was clearly presented by the Examiner and was set forth in the references themselves. Based upon this, a proper prima facie case of obviousness has been established and the rejection should be held as proper.

Claim 8

Appellant argues that Claim 8 is allowable due to its dependency on Claim 1. Further, in regards to the obviousness rejection of Claim 8 over Shah and Finsterle, Appellant argues that the purpose of comparing model output and measured data is to iteratively update the model parameters such that an optimal model is produced and that the goal in Finsterle of iteratively updating a model based on comparing model output and measured data is different from the subject matter of claim 8. Specifically, Appellant argues that a degree of certainty in the production rates allocated in claim 7 includes a degree of error in the model, and that such degree of error in a model is

compensated for in performing the inverting and that it is clear that Finsterle would not perform any compensating for a determined degree of error in the model in performing the inverting since the operator would assume that such an error in the model does not exist (pages 11-12).

It is the Examiner's position that Shah teaches the limitations of Claim 1 for the reasons stated above. Further, it is the Examiner's position that the combination of the teachings of Shah and Finsterle tech or suggest the limitations of Claim 8.

Specifically, the Examiner cited Shah for teaching determining a degree of certainty in the production rates allocated as recited in claim 7. As to the limitations of Claim 8, it is the Examiner's position that Finsterle, page 4, section (2) that recites, "...error analysis is performed..." as well as item (4) on page 7 clearly disclose determining a "degree of error in the model", wherein the differences between the measured and calculated system response is calculated (equation 1.5.3), that is, the “degree of error in the model” is determined. It is further the Examiner’s position that this error in the model is compensated for in the inversion process by iteratively updating model parameters to decrease the objective function as discussed on page 6, items 8 and 9, page 8, items 8 and 9 among other passages cited by the Examiner. It is further the Examiner’s position that it is clearly assumed by an operator that error in the model does exist as shown by page 7 (4).

Appellant further argues that even if Shah and Finsterle could be hypothetically combined, the hypothetical combination of references would not have lead to the subject matter of claim 8.

It is the Examiner's position that the limitations of Claim 8 are taught or suggested by the combination of the teachings of Shah and Finsterle.

Claim 9

Appellant argues that Claim 9 depends from Claim 1 and is therefore allowable for the same reasons as claim 1. Appellant further argues that in connection with claim 8, there would be no reason in Finsterle to compensate for a determined degree of error in the measured temperatures in performing the inverting (page 12).

It is the Examiner's position that Shah teaches the limitations of Claim 1 for the reasons stated above. Further, it is the Examiner's position that the combination of the teachings of Shah and Finsterle tech or suggest the limitations of Claim 9.

It is the Examiner's position that a reason to compensate for a determined degree of error in measurements (such as temperatures) in performing inverting is suggested in the cited portions of Finsterle. Specifically, Finsterle clearly teaches a degree of error in measurements (page 3, paragraph 2, lines 4-5), "…the available observations are incomplete and exhibit random measurement errors", wherein the error is taken into account in the model (page 10, item 5; page 27, element 2.5.3.1) "We assume that the measurement errors of the pressure data…", wherein the diagonal in the matrix shown (2.5.3.1) corresponds to the measurement errors. Finsterle further shows the measurement errors taken into account in the objective function to be minimized in the inversion algorithm shown on page 6 (page 11, 1.6.2). These cited

portions clearly show that measurement error exists and is compensated for in performing the inverting.

Appellant further argues that even if Shah and Finsterle could be hypothetically combined, the hypothetical combination would not have lead to the subject matter of claim 9.

It is the Examiner's position that the limitations of Claim 9 are taught or suggested by the combination of the teachings of Shah and Finsterle.

Claim 10

Appellant argues that Claim 10 depends from Claim 1 and is therefore allowable for the same reasons as claim 1 and moreover, Claim 10 is allowable for similar reasons as stated above with respect to Claims 8 and 9 (page 13). Appellant further argues that the hypothetical combination of Shah and Finsterle does not provide any teaching or hint of compensating for the determined degree of error in the well parameters in performing the inverting (page 13).

It is the Examiner's position that Shah teaches the limitations of Claims 1, 8 and 9 for the reasons stated above. Further, it is the Examiner's position that the combination of the teachings of Shah and Finsterle tech or suggest the limitations of Claim 10.

It is the Examiner’s position that the well parameters are analogous to the model parameter values that are estimated using the inversion procedure taught by Finsterle on page 6 and that compensating for the determined degree of error is clearly taught.

As taught by Finsterle, the parameters are estimated, and then the error between the estimations and the actual measured values is determined and "compensated for" (page 4, item (2), page 8, items (7) and (8)) by minimizing the objecting function by iteratively updating these model parameters.

It is the Examiner's position that the limitations of Claim 10 are taught or suggested by the combination of the teachings of Shah and Finsterle as cited by the Examiner.

Claim 33

Appellant argues that Claim 33 depends on Claim 26 and is therefore allowable for at least the same reasons as Claim 26, Moreover, Claim 33 is further allowable for similar reasons as stated above with respect to Claim 8 (page 13).

It is the Examiner's position, for the reasons stated above, that the references as applied teach the limitations of Claims 26, 8-10 and 33.

Claim 11

Appellant argues that the obviousness rejection of Claim 11 over Shah and Akin has been overcome in view of the allowability of base claim 1 over Shah (page 13).

It is the Examiner's position as stated above that Shah teaches the limitations of Claim 1. Further, it is the Examiner's position that the combined teachings of Shah and Akin teach or suggest the limitations of Claim 11.

Claim 16

Appellant argues that the obviousness rejection of Claim 12 over Shah and Curtis has been overcome in view of the allowability of Claim 12 over Shah (page 14).

It is the Examiner's position as stated above that Shah teaches the limitations of Claim 11. Further, it is the Examiner's position that the combined teachings of Shah and Curtis tech or suggest the limitations of Claim 16.

Claims 23 and 24

Appellant argues that the obviousness rejection of Claims 23 and 24 over Shah and Tubel has been overcome in view of the allowability of Claim 19 over Shah (page 15).

It is the Examiner's position as stated above that Shah teaches the limitations of Claim 19. Further, it is the Examiner's position that the combined teachings of Shah and Tubel teach or suggest the limitations of Claims 23 and 24.

For the above reasons, it is believed that the rejections should be sustained.

(11) Related Proceeding(s) Appendix

No decision rendered by a court or the Board is identified by the examiner in the Related Appeals and Interferences section of this examiner's answer.

Respectfully submitted,

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